Sixth Annual Conference on Carbon Capture & Sequestration

Steps Toward Deployment

CCS Economic Analyses

Carbon Dioxide Capture from Existing Pulverized Coal Power Plants

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Overview

<u>Purpose</u>: To perform a thorough engineering and economic analysis helps answer the following questions:

If carbon constraints are mandated in the U.S. then…..

1. Will retrofit of an **existing** pulverized coal plant at some **modest but non-trivial level** of CO_2 removal ever be a worthwhile option to consider?

2. What level of CO_2 recovery is economically optimal?

3. Is there a way to significantly reduce the cost of CO_2 capture for the **existing** fleet?

4. What actions would need to be taken to address **existing** power plants?

Carbon Sequestration From Existing Power Plants Feasibility Study

December 2005—December 2006

Randall Gas Technologies

Study Scope

1. 30%, 50%, 70%, 90% and CO_2 capture levels
2. Employ scrubbing technology advances
3. Detailed steam turbine analysis
4. CO_2 capture and compression heat integration

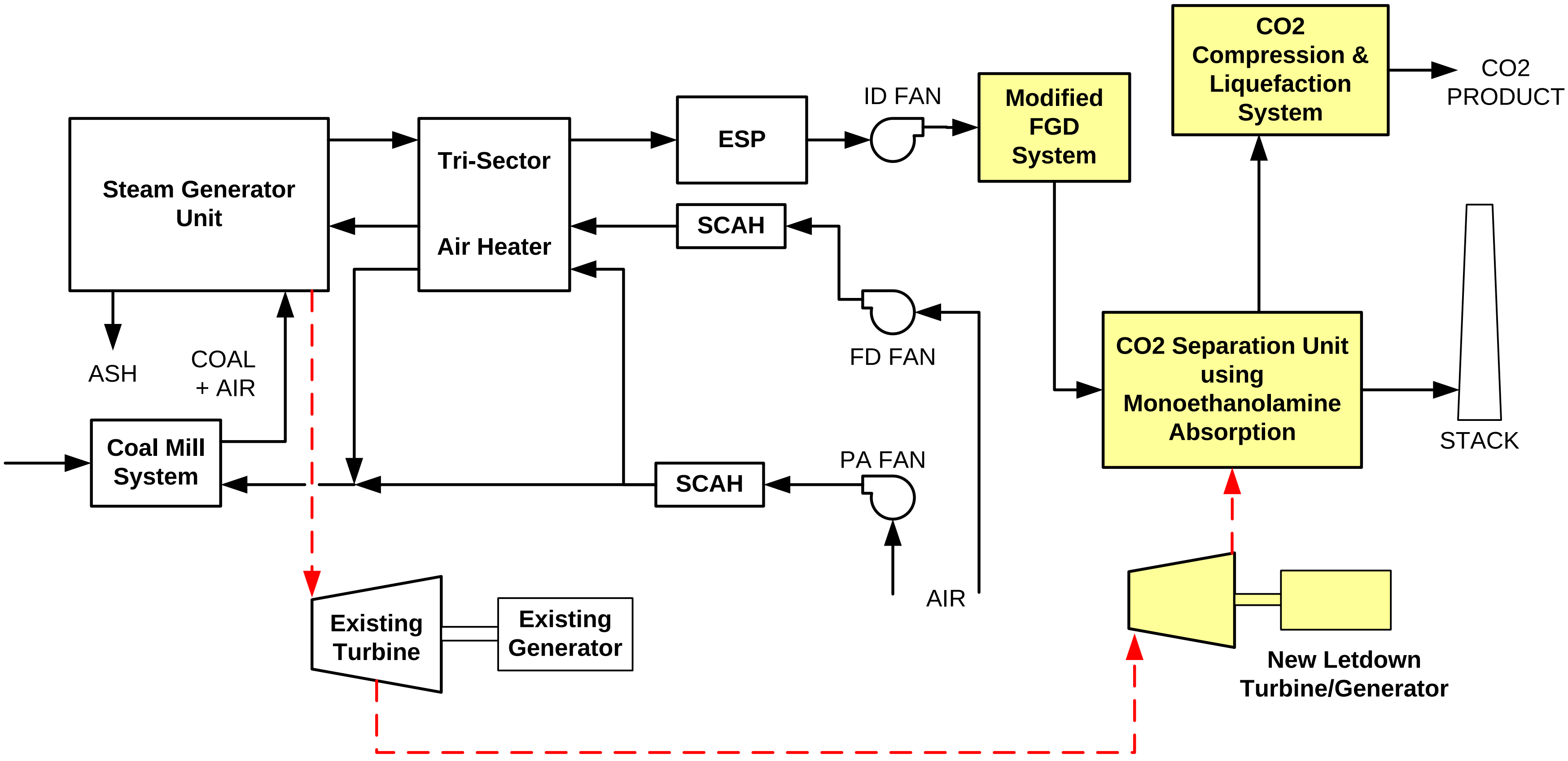
Location: AEP Conesville Unit #5

- **Total 6 units = 2,080 MWe**
- **Unit #5:**
  - Subcritical steam cycle (2400psia/1005^{o}F/1005^{o}F)*
  - Constructed in 1976
  - 463 MW gross (~430 MW net)
  - ESP and Wet lime FGD (95% removal efficiency, 104 ppmv)

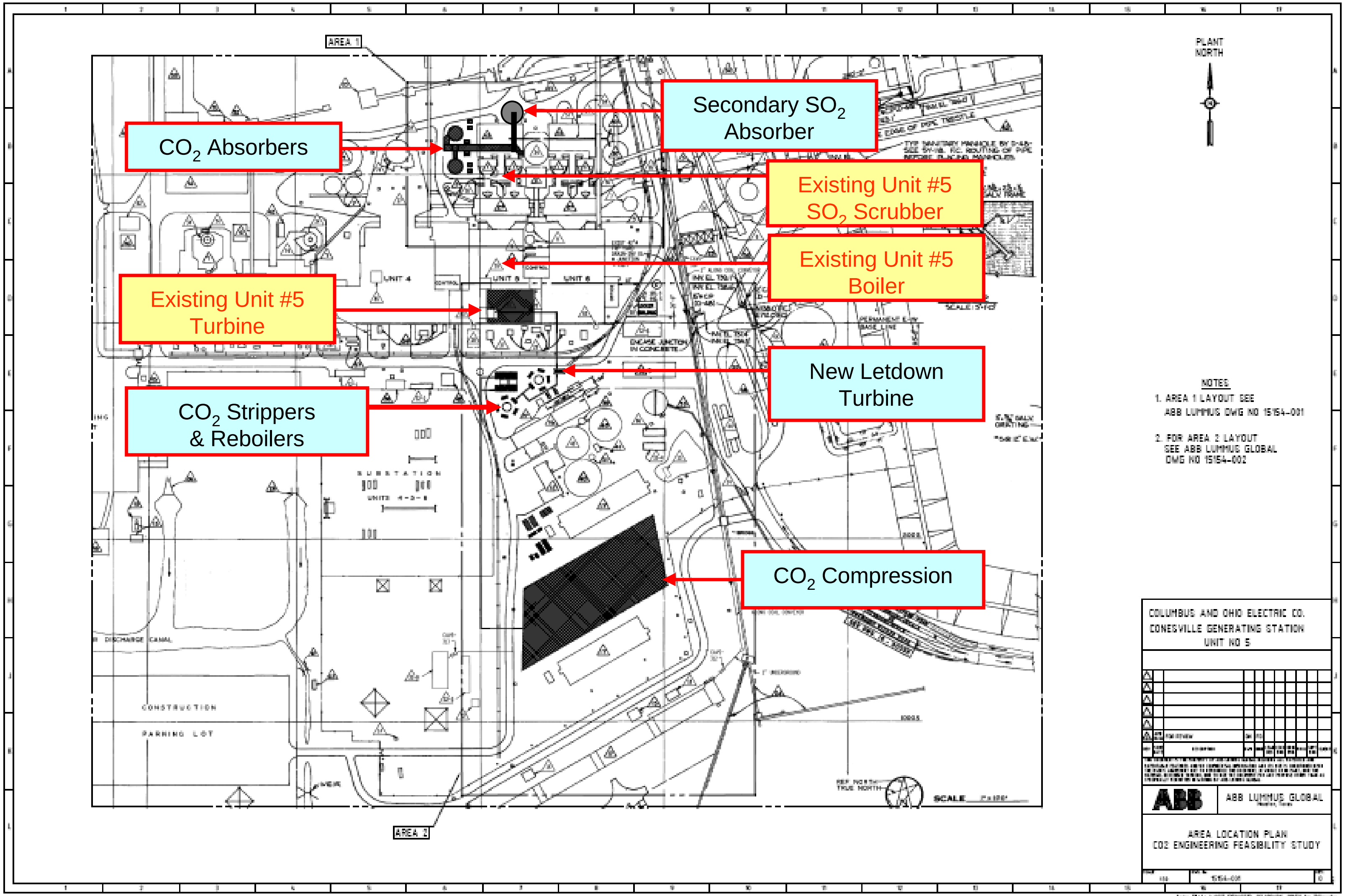
Mid-western bituminous coal

Ultimate Analysis (wt.%)	**As Rec'd**
Moisture	10.1
Carbon	63.2
Hydrogen	4.3
Nitrogen	1.3
Sulfur	2.7
Ash	11.3
Oxygen	7.1
HHV (Btu/lb)	11,293

Existing Plant Modifications

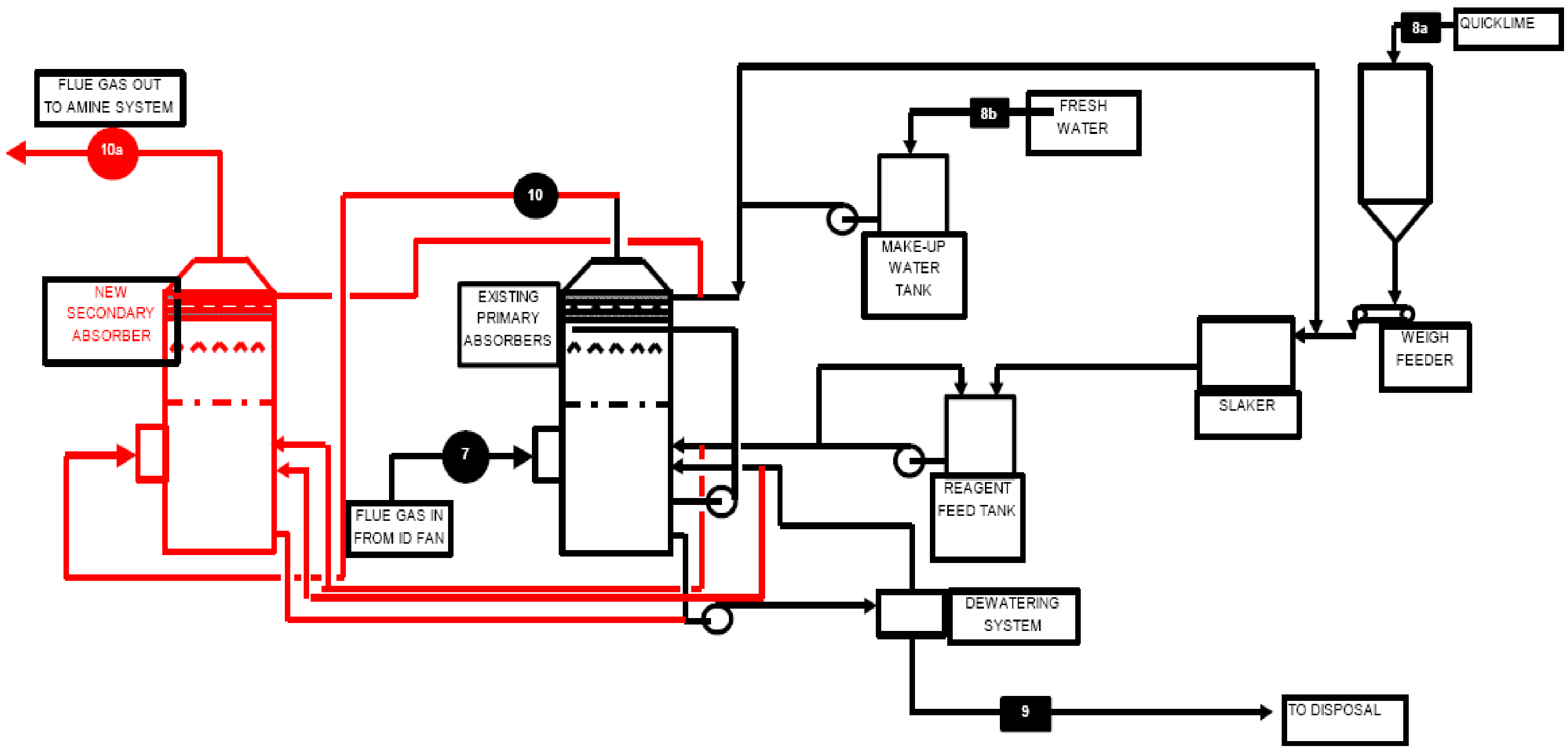


New Equipment Locations Identified



Modified FGD Process

1. Second stage absorber added to achieve 99.7% SO_2 removal efficiency (6.5 ppmv)
2. Includes an SO_2 Credit equal to $608/ton in the Variable O&M cost



CO_2 Capture Process Key Parameters

Process Paramater	Units	2006	2001	AES Design
Plant Capacity	Ton/Day	9,350-3,120	9,888	200
CO_2 Recovery	%	90-30	90	96
CO_2 in Feed	mol %	12.8	13.9	14.7
SO_2 in Feed	ppmv	10 (Max)	10 (Max)	10 (Max)
Solvent		MEA	MEA	MEA
Solvent Concentration	Wt. %	**30**	**20**	**17-18**
Lean Loading	mol CO_2/mol amine	**0.19**	**0.21**	**0.10**
Rich Loading	mol CO_2/mol amine	**0.49**	**0.44**	**0.41**
Steam Use	lbs Steam/lb CO_2	**1.67**	**2.6**	**3.45**
Stripper Feed Temp	^oF	205	210	194
Stripper Bottom Temp	^oF	247	250	245
Feed Temp to Absorber	^oF	115	105	108

Note: Additional data in “notes pages”

- Reboiler operated at 45 psia—reduced from 65 psia used in 2000 study
- Absorber contains two beds of structured packing

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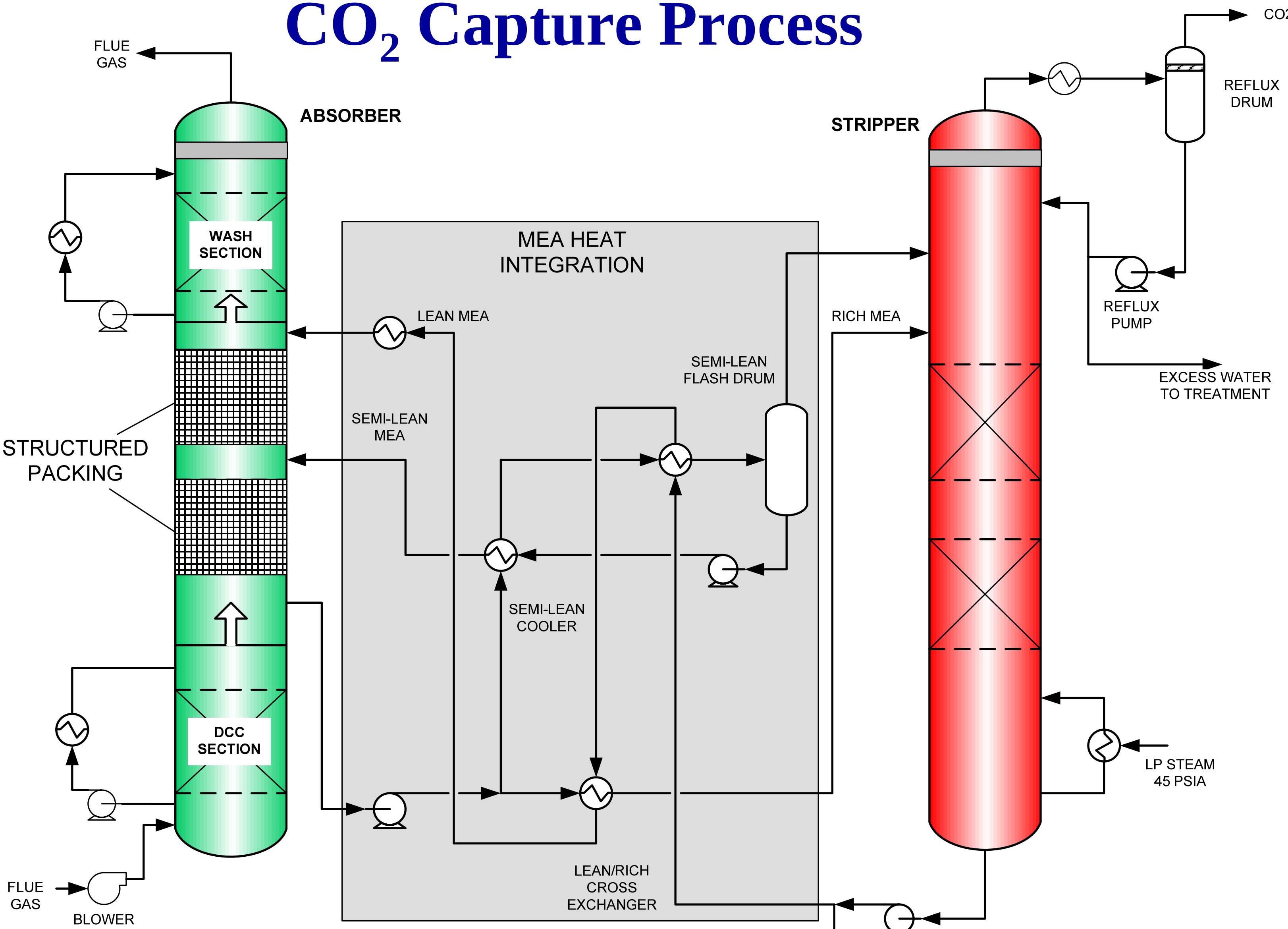
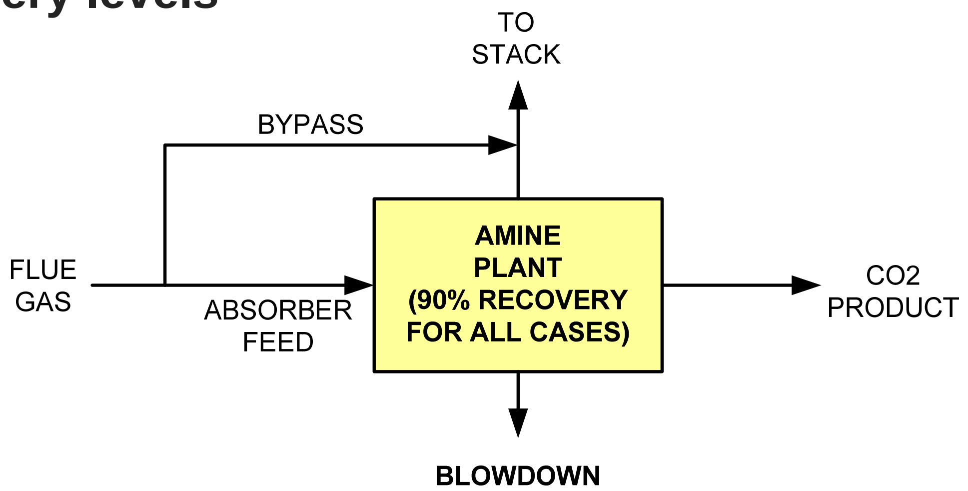
CO_2 Capture Process



Flue Gas Bypass

Bypass method determined to be least costly method to obtain lower CO_2 recovery levels



CO_2 (Moles/hr)	Case 1 (90%)	Case 2 (70%)	Case 3 (50%)	Case 4 (30%)
FLUE GAS	19,680	19,680	19,680	19,680
BYPASS	0	4,374	8,746	13,120
ABSORBER FEED	19,680	15,306	10,934	6,560
STACK	1,962	5,924	9,846	13,770
CO_2 PRODUCT	17,720	13,766	9,822	5,906
# Trains	2	2	2	1

CO_2 Capture Compression, Dehydration and Liquefaction

CO_2 compression to 2,015 psia, EOR specifications

Parameter	Wt %	Vol %	ppmv
Carbon Dioxide	96	94.06	940600
C_2+ and Hydrocarbons	2	2.87	28700
Hydrogen Sulfide	1	1.27	12700
Nitrogen	0.6	0.92	9200
Methane	0.3	0.81	8100
Oxygen	0.03	0.04	400
Mercaptans and Other Sulfides	0.03	0.02	200
Moisture	0.006	0.01	100

Four Stage Process:

Compression ⇨ Drying ⇨ Refrigeration ⇨ Pumping

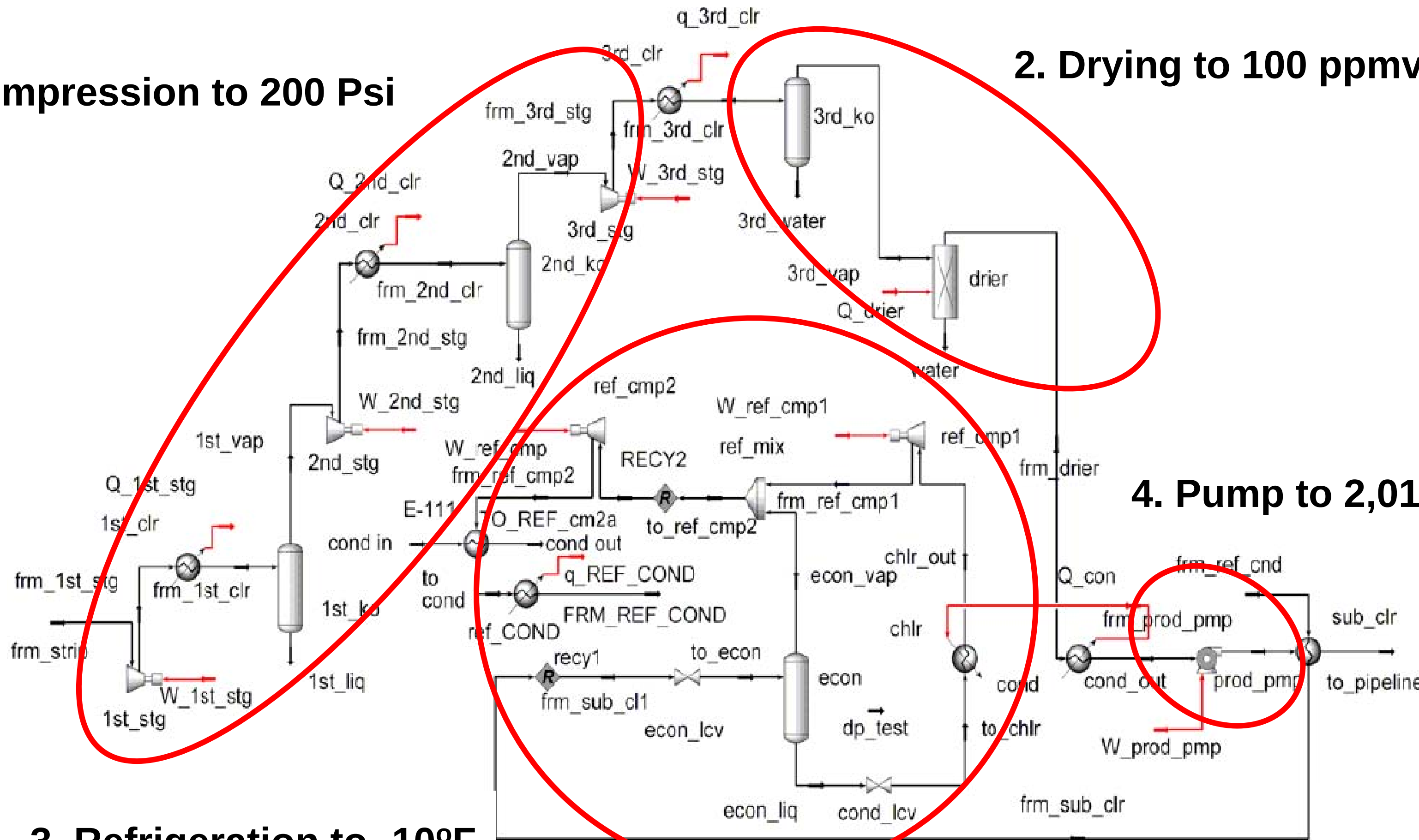
CO_2 Capture Compression, Dehydration and Liquefaction

1. Compression to 200 Psi

2. Drying to 100 ppmv H_2O

3. Refrigeration to -10ºF

4. Pump to 2,015 Psia



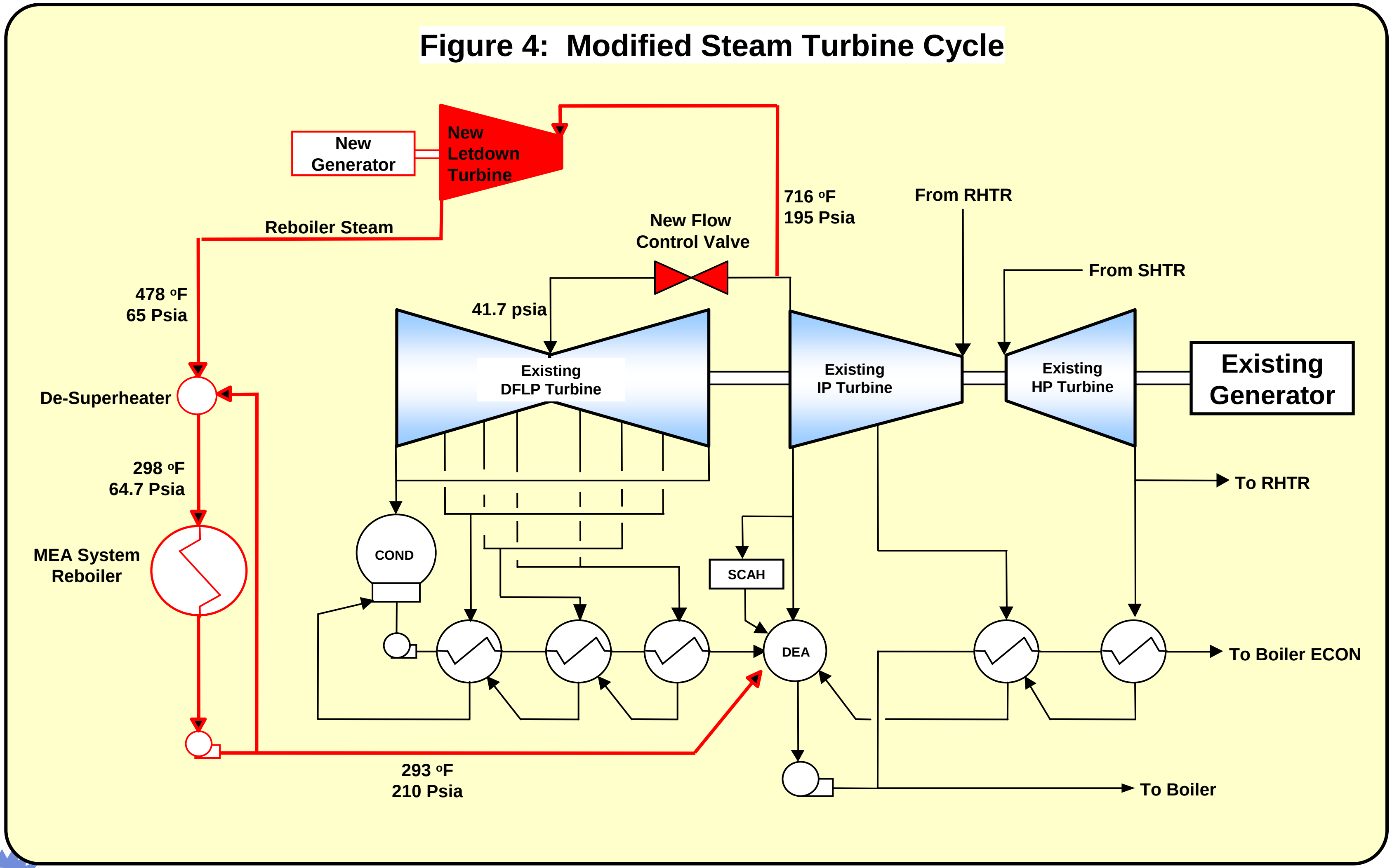
CO_2 Capture Process Equipment

CO_2 sorbent technology improvements leads to significant decrease in equipment requirements and capital cost!

	2006 Study		2001 Study	
CO_2 Capture Process	No.	ID/Height (ft)	No.	ID/Height (ft)
Absorber	2	34/126	5	27/126
Stripper	2	22/50	9	16/50
Distance from stack	100 ft		1,500 feet	
Heat Exchangers	No.		No.	
Reboilers	10		9	
Stripper CW Cond.	12		9	
Other Heat Exchangers	36		113	
Total Heat Exchangers	**58**		**131**	
CO_2 Compressor	2		7	
Propane Compressor	2		7	
EPC Cost $MM	**276**		**500**	

Steam Turbine Modifications

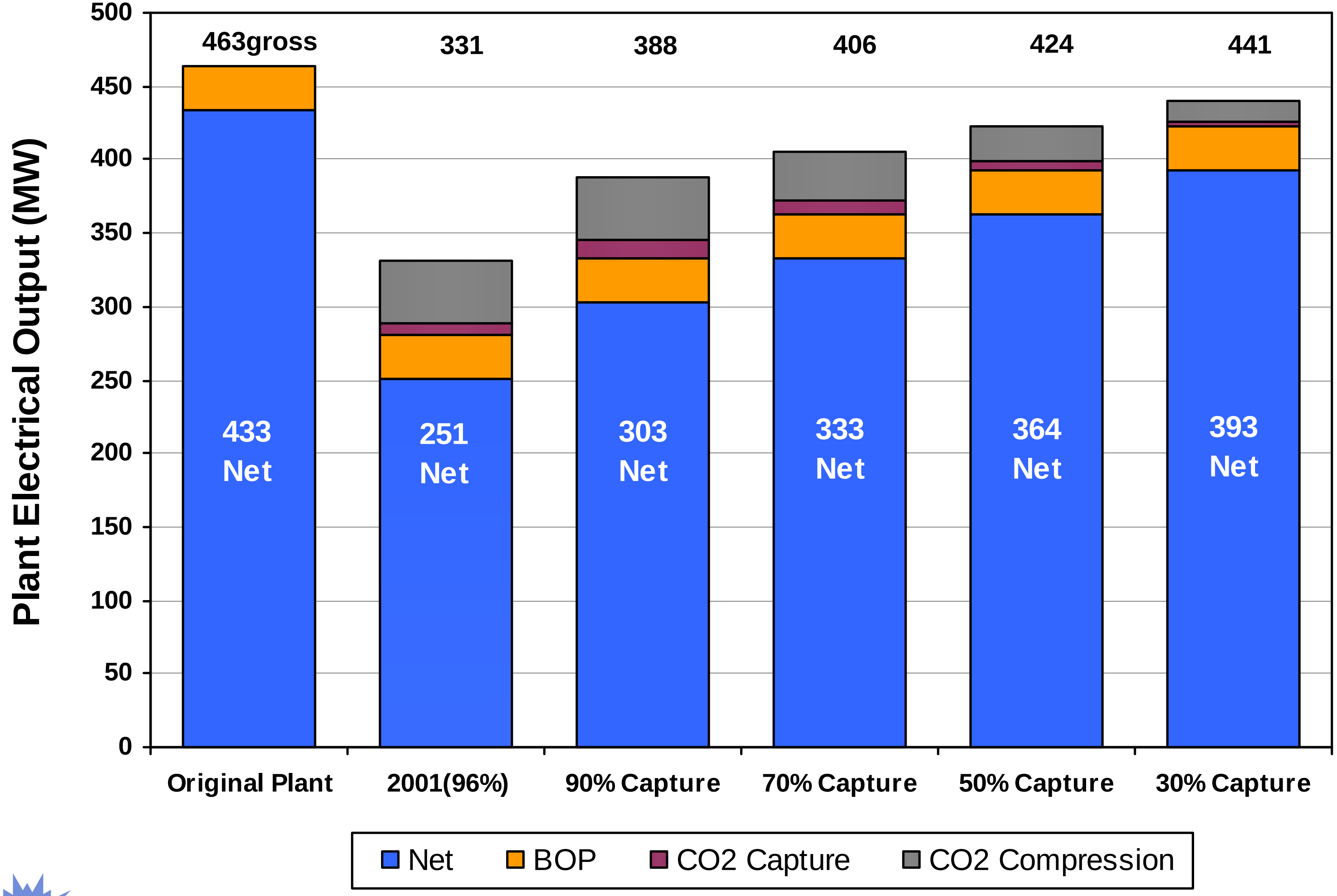
New Let Down Turbine



Overall Plant Performance

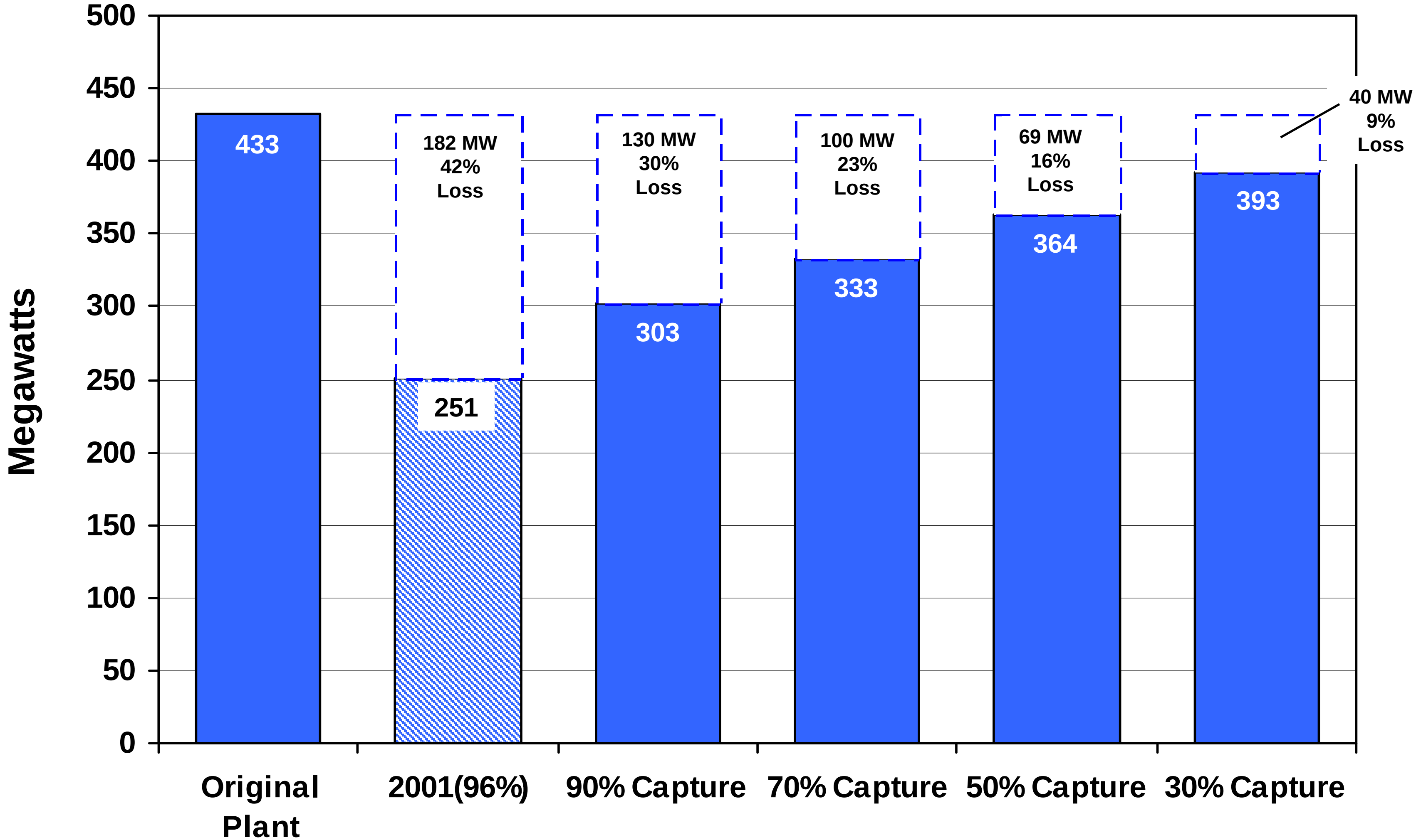
- Plant Electrical Output
- Plant Auxiliary Power
- Plant Thermal Efficiency
- Plant CO_2 Emissions

Power Output Distribution

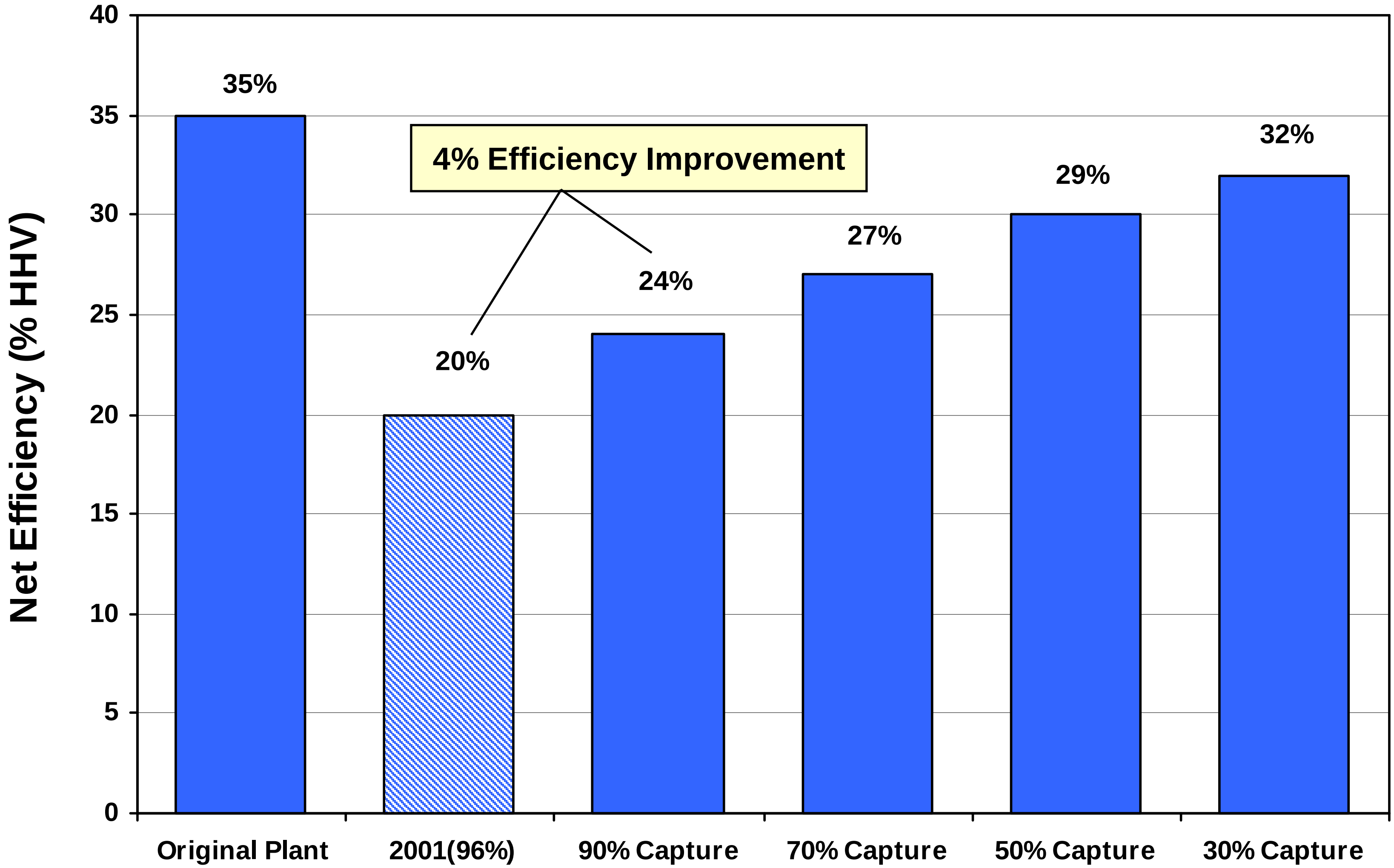


Base load (Net) Output Impact

Losses to Grid

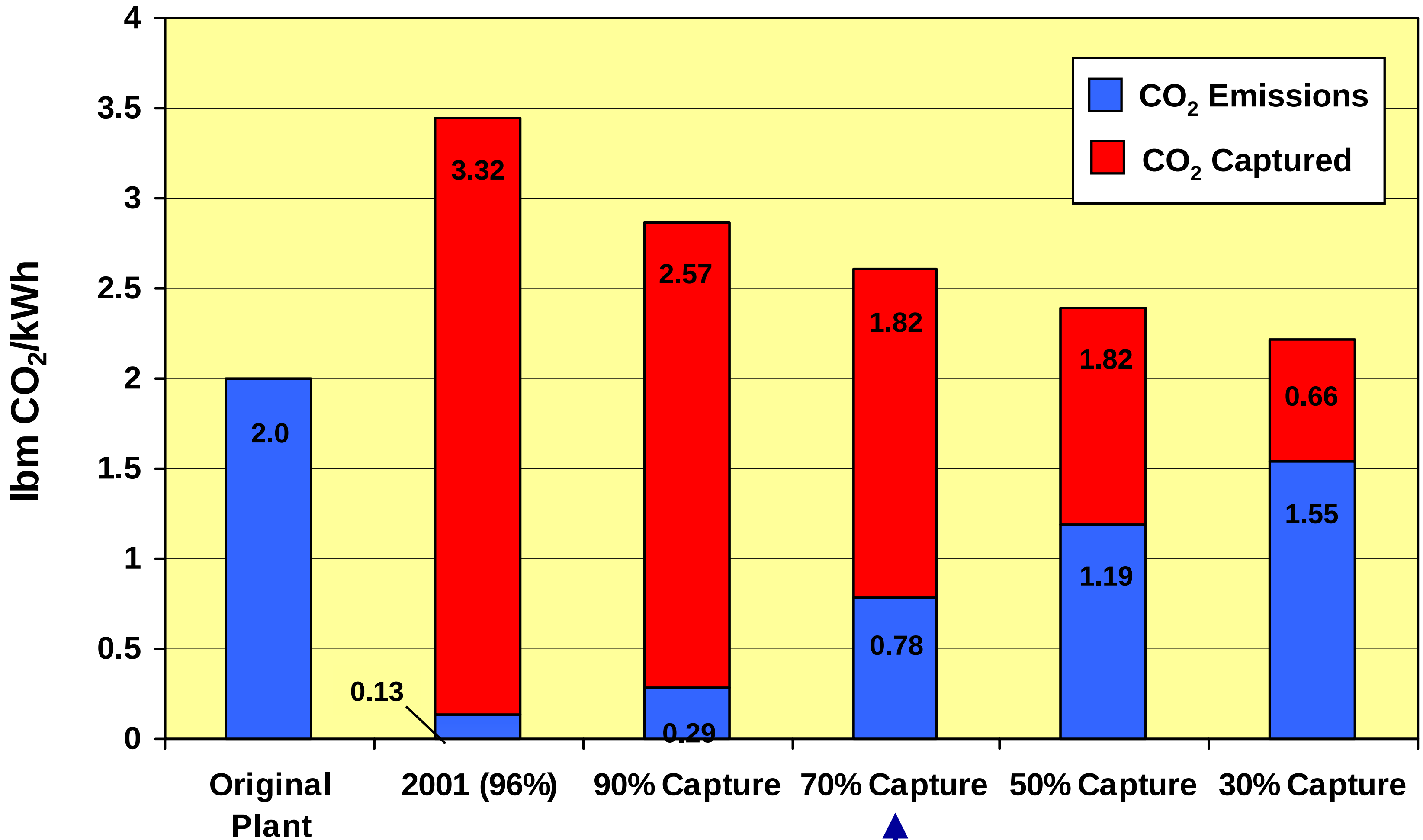


Plant Thermal Efficiency
(HHV Basis)



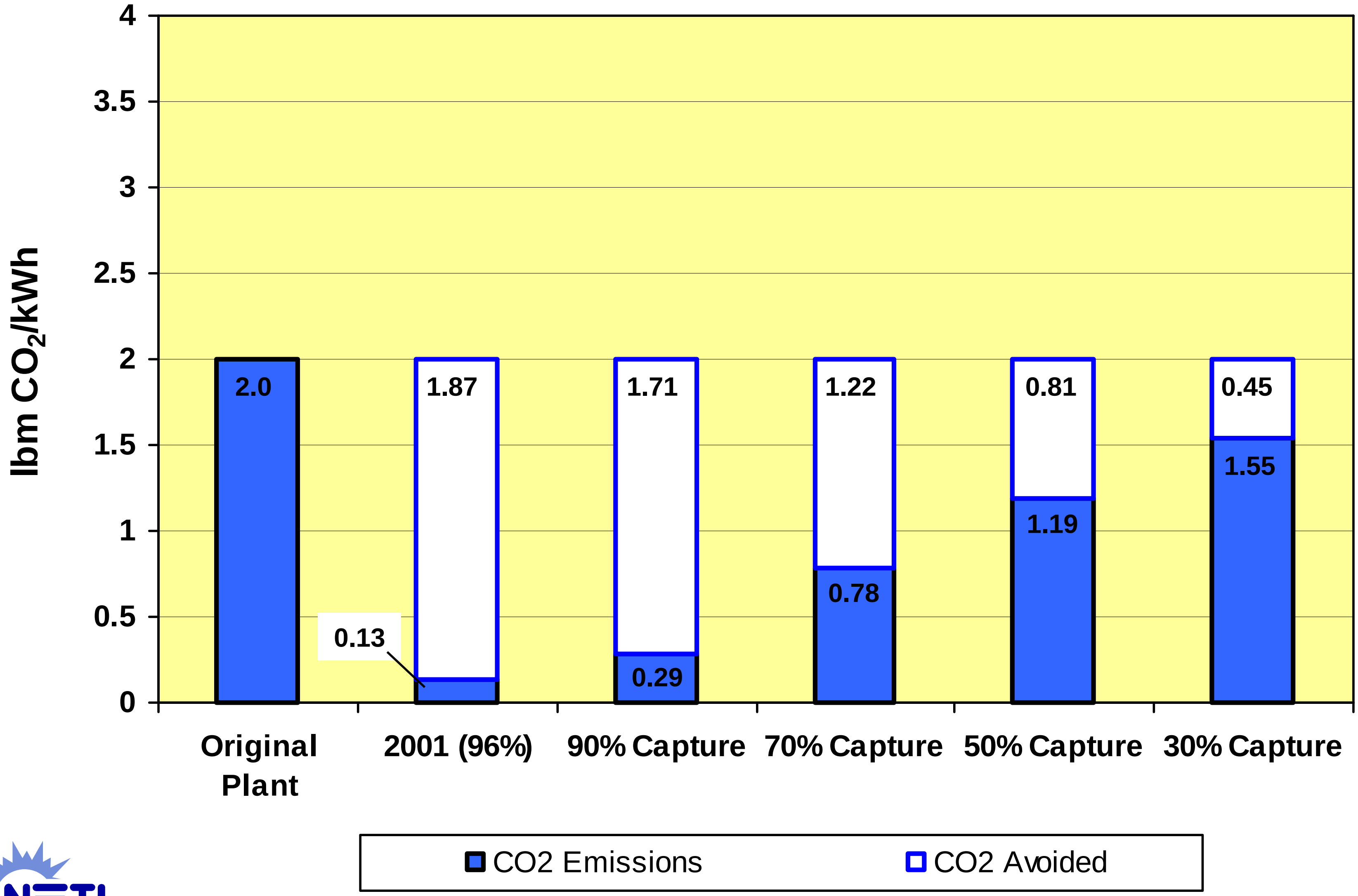
Note: NEW Sub-critical net efficiency (with 90% CO_2 capture) decreases from 36% to 24%

CO_2 Captured



CO_2 Emissions equal to NGCC without CO_2 Capture at ~ 0.8 lb/kWh

CO_2 Avoided Emissions



Economic Assumptions

Dollars (Constant)	2006
Depreciation (Years)	15
Equity (%)	44
Debt (%)	56
Corporate Tax (%)	20
Discount Rate (%)	7.5
Capital Charge Factor (%)	13.5
Coal ($/MM Btu)	2.11
Capacity Factor (6,307 hr/yr)	72

CO_2 transport and Storage Costs not included

Plant Retrofit Capital Costs

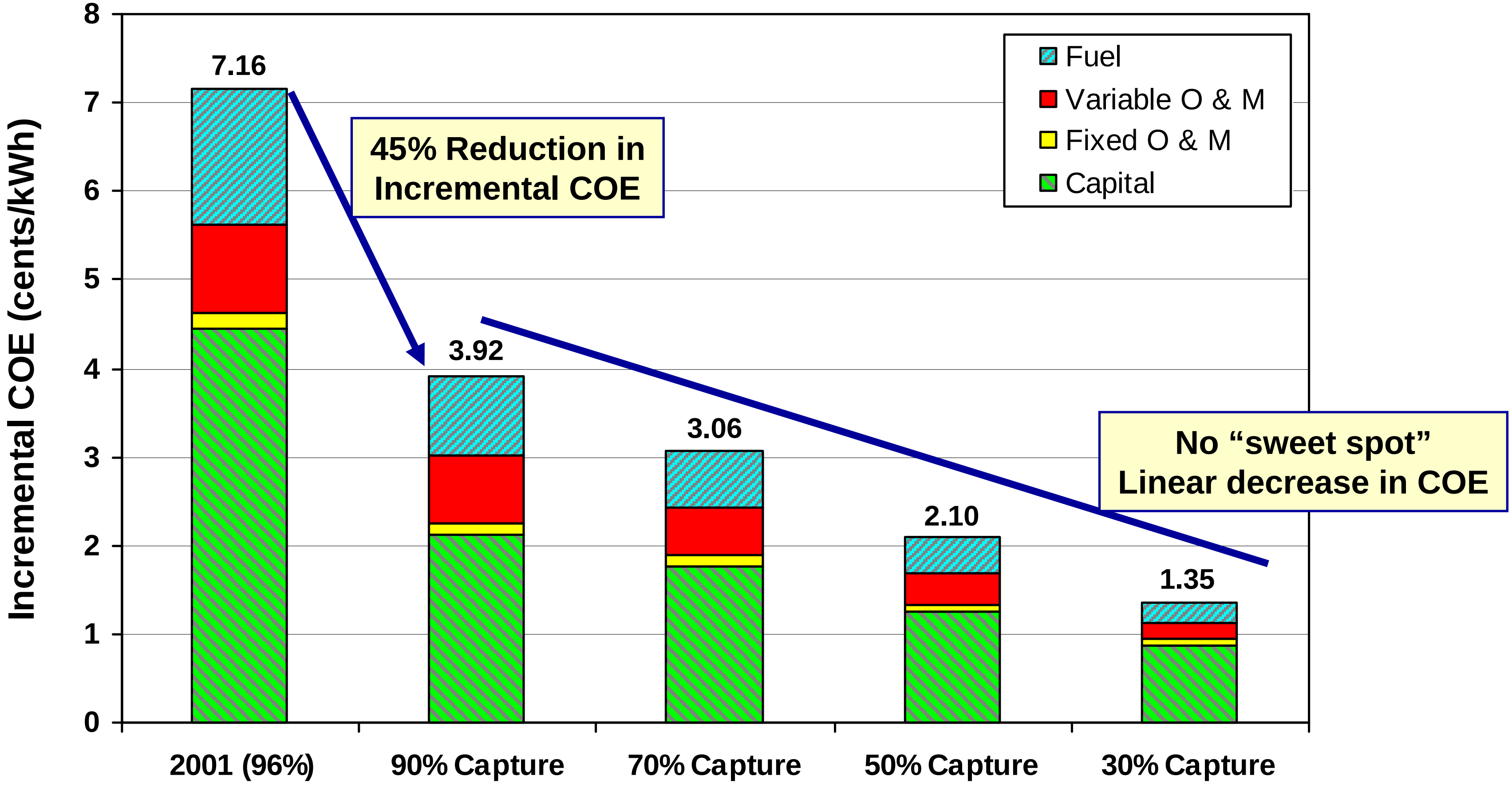
EPC Costs ($1000's)	2001	2006 Study			
% CO_2 Capture	**96**	**90**	**70**	**50**	**30**
CO_2 Capture & Compression	500,807	275,938	249,822	186,694	134,509
Flue Gas Desulfurization	20,540	20,540	20,540	20,540	20,540
Letdown Steam Turbine	10,516	9,800	9,400	8,900	8,500
Boiler Modifications	0	0	0	0	0
Total Retrofit Costs	**531,863**	**306,278**	**279,762**	**216,134**	**163,549**
New Net Output (kW)	251,634	303,317	333,245	362,945	392,067
$/kW-New Net Output	**2,114**	**1,010**	**840**	**596**	**417**
$/kW-Original Net Output*	**1,226**	**706**	**645**	**498**	**377**

*Original net output = 433,778 kW

52% Reduction in Incremental Capital Costs

__Note__: Capital costs from 2001 study were escalated to 2006 dollars

Economic Results



Mitigation Costs:
$/Ton CO_2 Removed = $30 - $41
$/Ton CO_2 Avoided = $46 - $60

Note:
Economic results from 2001 study were escalated to 2006 dollars
Variable O&M cost includes SO_2 Credit at $608/ton

Summary & Conclusions

1. No major technical barriers found

2. Compared to the 2001 study, this study with an advanced amine (90% CO_2 Capture case) showed:
   - Marked improvement in energy penalty and reduction in cost

3. No Sweet Spot—near linear decrease in incremental COE with reduced CO_2 capture level

4. Sufficient results to answer various definitions of "optimal CO_2 capture" from existing plants

Thank You!

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NETL Energy Analysis Link:
www.netl.doe.gov/energy-analyses